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Citation for published version:

Turk, J, Reay, D & Haszeldine, R 2018, 'UK grid electricity carbon intensity can be reduced by enhanced oil recovery with CO₂ sequestration', *Carbon Management*. <https://doi.org/10.1080/17583004.2018.1435959>

Digital Object Identifier (DOI):

[10.1080/17583004.2018.1435959](https://doi.org/10.1080/17583004.2018.1435959)

Link:

[Link to publication record in Edinburgh Research Explorer](#)

Document Version:

Publisher's PDF, also known as Version of record

Published In:

Carbon Management

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To cite this article: Jeremy K. Turk, David S. Reay & R. Stuart Haszeldine (2018): UK grid electricity carbon intensity can be reduced by enhanced oil recovery with CO₂ sequestration, Carbon Management, DOI: [10.1080/17583004.2018.1435959](https://doi.org/10.1080/17583004.2018.1435959)

To link to this article: <https://doi.org/10.1080/17583004.2018.1435959>



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Published online: 22 Feb 2018.



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UK grid electricity carbon intensity can be reduced by enhanced oil recovery with CO₂ sequestration

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ABSTRACT

Enhanced Oil Recovery (EOR) using CO₂ coupled with Carbon Capture and Storage (CCS) can potentially accelerate CO₂ storage investment through creation of a large commercial market for EOR. This article assesses how coupled a CCS-EOR scenario might contribute to decarbonization of UK grid electricity. Progressive introduction of 11 CCS-to-EOR gas-power plant projects from 2020 is estimated to store 52 Mt CO₂ yr⁻¹ from 2030. These 11 projects produce extra revenue of 1100 MM bbls of taxable EOR oil from 2020 to 2049. After each 20-year EOR project ceases, its infrastructure is paid for, and has many years of life. UK climate change targets would necessitate continued CO₂ storage at low cost. Considering all greenhouse gas emissions – from power generation, CCS-EOR operations, and oil production and combustion – this project suite emits an estimated 940–1068 Mt CO₂e from 2020 to 2049, while storing 1358 Mt CO₂. The total average electricity grid factor in the UK reduces to 90–142 kg CO₂e MWh⁻¹, with gas generating 132 TWh yr⁻¹. This life-cycle analysis (LCA) is unusual in linking oil production and combustion with CCS and gas-fueled electricity, yet provides a net carbon reduction, and progressively reduces net oil combustion emissions beyond 2040.

KEYWORDS

carbon capture and storage; enhanced oil recovery; life-cycle analysis; gas-fueled power plants; CO₂ utilization and storage market

Introduction

The UK is legally bound to reduce greenhouse gas (GHG) emissions by 80% of 1990 levels by 2050. Within this goal, the Committee on Climate Change (CCC) recommends the GHG intensity of electricity generation fall to 50–100 kg CO₂ per megawatt hour (MWh) by 2030 [1,2]. Total UK electricity generation (including pumped storage) fell by 5.6% from 359 terawatt hours (TWh) in 2013 to 339 in 2015; gas-fired generation increased from 96 TWh in 2013 to 100 TWh in 2015, representing 30% of total supply [1,2]. Coal-fired generation fell from 131 TWh in 2013 to 76 TWh in 2015, and is projected to continue to decline rapidly through the next decade [3–4] due to Electricity Market Reform [5] and The Industrial Emissions Directive [6]. However, according to government projections published in 2017, the UK is projected to need 96 gigawatts (GW) of new peak electricity generation capacity by 2035 to replace coal-fired generation, support renewables intermittency, and meet decarbonization goals. Unabated gas power is projected to deliver 35 TWh by 2035, up from 28 TWh in the previous projections [7,4]. The UK's Department for Business, Energy & Industrial Strategy (BEIS) indicates that this 20% increase in unabated gas electricity delivery will come from gas infrastructure with 20% reduced capacity in their latest projections [7,4] for

the years 2031–2035, compared to previous projections. This suggests that gas power will continue to be used at very high load factors, being relied upon for peaking power, yet there will be less built capacity. This indicates a projected reliance on a high level of gas fossil fuels in power generation.

GHG emissions from power generation are traded as part of a UK–European Union Emissions Trading Scheme (EU ETS) capped market, and do not affect the UK's ability to meet carbon budgets. The continued use of fossil fuels by major power producers (MPPs), companies whose primary activity is electricity generation [8], maintains a domestic demand for fossil fuels which can create consequential emissions in other non-traded sectors of the economy (e.g. fugitive CH₄ emissions from coal and gas extraction). Despite cuts in coal-fired capacity [5,6] and increased renewable capacity, BEIS indicates a gap in meeting Carbon Budgets 4 and 5, of 146 and 247 Mt CO₂e, respectively [4]. The projections include a 27% increase in interconnection capacity by 2035, which delivers electricity that does not affect the UK carbon targets, and is ostensibly zero carbon for the UK. Uncertainty in reaching grid decarbonization goals through UK electricity generation places increased reliance on buying electricity through interconnection from elsewhere in Europe, and carbon offsets through the EU ETS. With the UK's place in the EU now in political negotiation, meaning

EU ETS will not be available in future, this study examines an independent multi-decadal plan to aid UK grid decarbonization, and provide domestic oil production.

Carbon capture and storage (CCS) use in conjunction with large point sources of CO₂ emissions, such as power plants, is a key technology to support plans to meet UK decarbonization goals [3,7], but investment and profitability issues have thus far limited CCS development in the UK [9–10]. The UK's Department of Environment and Climate Change (DECC) [11] concluded that electricity with CCS in the UK would cost between £64 and £128 MWh⁻¹ while electricity with unabated gas costs between £63 and £109 MWh⁻¹. Similarly, Rubin and Zhai [3] reported the cost of CCS as \$76–114 MWh⁻¹ (mean \$93) and that of unabated gas as \$52–75 MWh⁻¹ (mean \$63). The latter study also estimated a carbon tax of \$73 per t CO₂ as being the break-even point where CCS and unabated gas power generation reach equal cost. Welkenhuysen *et al.* [4] probabilistically allocated Monte Carlo cycles to oil production uncertainty and selling price uncertainty and found that enhanced oil recovery (EOR) in the North Sea has positive net present value with an oil price above €50 bbl⁻¹. In the absence of a direct CCS subsidy or a high carbon price, EOR coupled with CCS has the potential to bridge this gap in costs between unabated gas and CCS [4,5].

This article examines the potential impact of such a transition to coupled EOR-CCS on grid intensity and GHG emissions in the UK through to 2035 and beyond. The paper assesses the size and number of EOR-supported CCS projects needed to satisfy projected CCS capacity projections by DECC [7], electricity decarbonization targets [1,2], and CO₂ storage goals by Element Energy [12]. A unique perspective is provided, of extending life-cycle analysis (LCA) estimates of grid electricity and downstream interventions to reduce grid emissions in the UK via EOR-CCS. Previous EOR studies excluded emissions associated with venting and flaring recycled CO₂ and CH₄ [6], or were too dissimilar in location and upstream fuel type [7]. Note that a modified amount of CCS electricity predicted in

2017 [4] for the UK is linked to the perception of CCS under current government policies; it is not a target or pathway. In simple terms the amount of CCS electricity changed from 2016 [7] to 2017 [4] has been replaced by a similar amount of 'zero carbon' electricity imports, with no plan for delivery. This analysis offers scenarios for a cash-poor government to obtain development of CCS, maintain electricity, keep high employment and conduct efficient oil extraction from the UK offshore.

Methodology

In order to assess cradle-to-grave emissions of an EOR chain with natural gas combined cycle (NGCC) electricity, first the LCA of Stewart and Haszeldine [8] was extended to include upstream phases (see Figure 1). Stewart and Haszeldine [8] examined two EOR scenarios to assess GHG balances in a CO₂ storage-focused system compared to an oil recovery-focused system. The current study uses a storage-focused system and extends the LCA scope upstream to include power capacity needs, coupled EOR-CCS development over the next 20 years, and further CO₂ storage via CCS beyond 2040. This paper's estimations assume that CO₂ stored through EOR would have otherwise been emitted through unabated gas power. This unabated gas pathway in the UK is implied by DECC's 2015 projections of development of new-built gas capacity, used intensively to deliver electricity from unabated gas through to 2035 [7,4]. Stewart and Haszeldine [8] focused on EOR emissions and present results in t CO₂ emitted or stored per barrel of incremental oil produced. The focus is shifted upstream to examine implications of the modeled interventions on grid electricity targets. The EOR literature is split between including [9,13] or excluding [10] oil emissions in estimates. The CCS and EOR emissions are incorporated, along with imported and produced oil emissions during EOR, because they are a direct result of EOR interventions, and encompass the net GHG emissions more fully. To make comparisons with the business as usual (BAU) unabated gas pathway in kg CO_{2e} MWh⁻¹, the

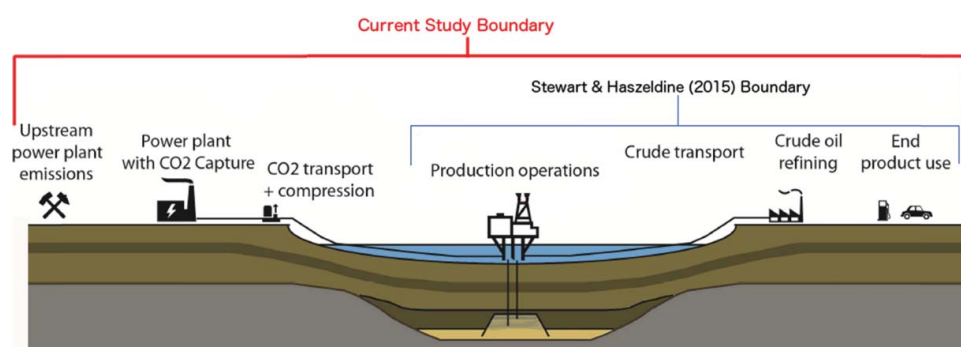


Figure 1. This study extends the upstream boundary of Stewart and Haszeldine to include upstream fossil fuel production and power plant carbon dioxide (CO₂) emissions. Figure adapted from Stewart and Haszeldine [8].

modeled sums of all emissions are divided by the delivered grid electricity to give LCA estimates in kg CO₂e MWh⁻¹, units normally used for grid factors, not LCAs.

Natural gas supply and demand

In 2015, the UK consumed 741 TWh of gas from domestic and imported sources [2,7]. The total gas supplied was 861 TWh, of which 47.7% was met by UK sources. Imported pipeline gas (34.7%) came from Norway, Belgium and The Netherlands via interconnections [14]. An additional 152 TWh of liquefied natural gas (LNG) was supplied from Qatar (16.4%), Algeria (0.6%), Trinidad and Tobago (0.6%), and Nigeria (< 0.1%). UK net gas production was 410 TWh in 2015 (460 TWh total minus 50 TWh used by producers), and UK gas production is expected to fall by 5% yr⁻¹ from 2020 until 2035, while demand is expected to remain steady [7,14,15].

To satisfy the predicted requirement for electricity generation capacity in 2035 [7] and CO₂ storage required to meet grid electricity GHG targets [12], a scenario was developed based around the build of 11 new gas-fueled electricity power plants, each of 1930 MW capacity and producing 5.56 Mt CO₂ yr⁻¹ per plant (see below). The grid emissions intensity of this portfolio of unabated gas plants was then compared to the same portfolio fitted with CCS and coupled to EOR operations offshore (North Sea). Under this scenario, additional oil produced through the coupled EOR-CCS system would displace imported oil production and would use CO₂ from each of the 11 power plants.

For the purposes of estimating upstream GHG emissions it was also assumed that the gas power plants are supplied with gas from the UK National Transmission System (NTS). When gas arrives in the UK via interconnection or LNG terminal, it enters the NTS, making the geographic origin for the customer unknown. The net gas flows between the UK and Belgium and The Netherlands have represented $\pm 1\%$ of total supply since 2010 [14], and are therefore regarded as irrelevant for GHG estimation in this study. In the absence of nation-specific data, LNG imports from Nigeria and Trinidad and Tobago are assumed to have the same GHG emissions footprint as LNG from Algeria. Finally, imported North Sea gas is assumed to have the same emissions footprint as UK domestic gas.

To estimate UK gas supply, usage and related GHG emissions to 2050, the projected gas demand from DECC was used [7], in the same geographic proportions (places of origin) as the current gas supply entering the NTS, as described above.

CCS and future UK electricity supply

Our assumptions on UK electricity production and CCS roll-out are based on the DECC reference scenario [7].

Recent projections by BEIS [4] severely cut expected CCS capacity to just 963 MW in 2035, the final year of the projections. This modeled cut is in response to the UK government's withdrawal of £1 billion funding for CCS. These same BEIS projections also indicate a gap in Carbon Budgets 4 and 5, described above. The UK government has since released a plan to invest up to £100 million in CCS development [16], which would still fall short of reaching mid-century carbon reduction goals [17]. Considering these recent funding cuts, and reiterated gaps in legally binding carbon targets and pathways, this study considers the previous CCS projections from DECC [7] and storage targets from Element Energy [12] as benchmarks for grid decarbonization goals and actions. The project output is multiplied by 11 to achieve these benchmarks, and the needed capacity is explored (see below).

An estimated 365 TWh of electricity would be produced domestically in the UK in 2035 with nearly 40 TWh of this expected to be produced from coal and natural gas CCS. Unabated natural gas is projected to supply 44 TWh by 2035 [7]. In the shorter term it is assumed – again, based on the DECC reference scenario – that 638 MW of CCS capacity will be in place by 2019, increasing to 8382 MW by 2035. DECC [7] projects that the electricity generated by CCS plants would be utilized for baseload power (85% load factor) by 2022, then be reduced to less than 70% after 2030 (see Figure 2). A reduction in CCS load factor could have adverse effects on CO₂ capture rates and delivery to offshore injection sites. For simplicity, it is assumed that the electricity generated by the CCS plants would then be utilized for baseload power from 2022 onward with a continuous 85% load factor.

To assess the GHG impact of natural gas electricity generation and infrastructure, an LCA was scaled from Stamford and Azapagic [11]. All phase emissions in the Stamford and Azapagic LCA are proportionally increased, and operational emissions equal to the onshore CO₂ required for Stewart and Haszeldine [8]. This assumes equal combustion (operational) emissions at a gas plant regardless of gas origin, and so shifts CO₂ emissions variance for natural gas power plants to production and transportation emissions. The scaling method without CO₂ capture indicates that 96.4% of emissions associated with North Sea gas power are from combustion emissions, with a total output of 14.4 TWh yr⁻¹ per plant before CO₂ capture. The combustion emissions intensities for all natural gas plants are assumed to be equal and from steady state combustion, at 386.3 kg CO₂e MWh⁻¹. This figure is from a proprietary data set by Ecoinvent [18], and falls within the calculated range of 365–415 kg CO₂e MWh⁻¹ annually reported by DECC [1,12,8,19]. As such, onshore emissions total 5.56 Mt CO₂ yr⁻¹ for each of the 11 new unabated gas-fired power plants in the projections. This is considered the

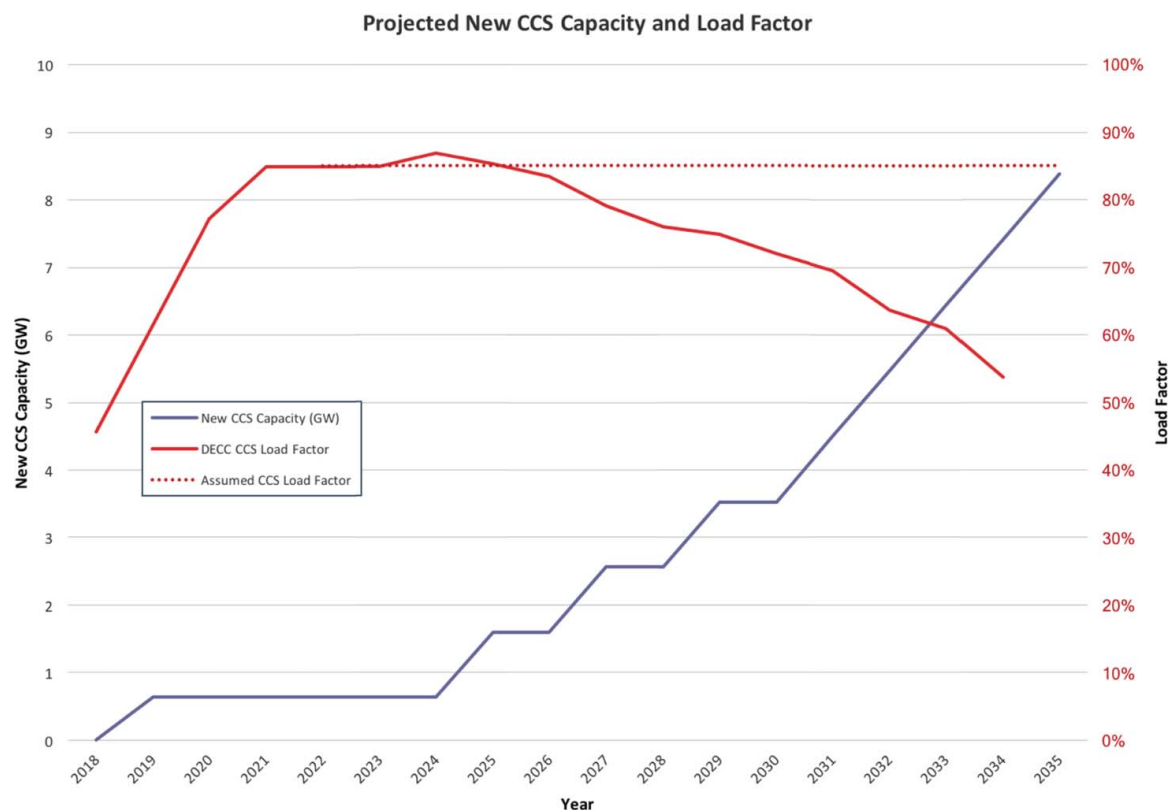


Figure 2. Projected new CCS capacity from the DECC [7] reference scenario. Load factor is calculated from projected delivered electricity divided by capacity. DECC projections suggest using CCS plants for baseload power (85% load factor) early next decade before reducing to 70% after 2030. For simplicity, a continuous 85% load factor is assumed in the models.

BAU case, projected to supply 44 TWh of unabated electricity [7] by 2030.

For coupled EOR-CCS it is assumed that 90% of CO₂ operational emissions from the gas power plants (equivalent to 5.0 Mt CO₂ yr⁻¹) will be captured onshore and transferred offshore to EOR operations (see Figure 1). The carbon capture energy penalty was assumed to be 16% of total output – the mean value of recent findings ranging from 13 to 18% for NGCC retrofits [13]. Note that Stamford and Azapagic [11] assume a plant efficiency of 52.5% based on lower heating value (LHV), whereas DECC [1] lists the average for the UK as 47.0% based on LHV. Using the DECC figures would increase the combustion emissions relative to the 52.5% LHV value used in the projections.

The upstream emissions associated with CO₂ capture for EOR from Stewart and Haszeldine [8] are identical to the CCS upstream emissions for each respective 20-year case study considered here. Both CCS and EOR models capture 90% of CO₂ from their respective power plants, and have identical grid electricity outputs for the fuel sources. The EOR models have additional operational emissions and reduced CO₂ storage associated with venting, and CO₂ recycling as described in Stewart and Haszeldine [8]. It is assumed that post-capture CO₂ or EOR does not need additional compression for, or during, transportation to offshore platforms, compared to the CCS case. The energy cost associated with compression and transportation of

CO₂ to offshore platforms is assumed to be minimal. For pipeline distances greater than 1000 km, 6.5 kWh per tonne of CO₂ is required for recompression [9]. This equates to less than 0.3% additional energy cost per project. When including coupled EOR-CCS operations, this figure is further diminished. In an offshore environment, these costs could increase, but would be mitigated by clustering of projects [4], reuse of current pipeline infrastructure [20] and shorter pipeline distances [9]. This is an area in need of further study, but it is not cost-prohibitive or significantly impactful on the full project GHG balances. Any energy and associated emissions required to compress or recompress CO₂ specifically for EOR are therefore excluded.

Offshore, CO₂ injection operations incur one-time fixed emissions demonstrated in EOR models [8]. New well drilling, well workover and steel construction are 45,816 t CO₂e. For coupled CCS-EOR, annual offshore operational emissions include fugitive CO₂, and additional offshore CO₂ compression for injection equal to 57,723 t CO₂e yr⁻¹ [8]. Values greater than 4 Gt CO₂ storage capacity in UK offshore oilfields and greater than 2000 MM bbls recoverable EOR oil are assumed [14,20]. Liability and decommissioning costs for these systems remains uncertain [20,21]. This study assumes zero liability, and excludes decommissioning costs. Costs associated with extending the life of offshore platforms can be offset by proper investment of funds for decommissioning. Welkenhuysen *et al.* [4] suggest

that interest payments will create a positive cash flow, more than covering the cost of extending the life of offshore operational infrastructure. The storage liability would transfer at sale to an operator who can profit from production of EOR oil, but would likely transfer back to government if EU ETS CO₂ prices remain low. However, this is an area in need of future study.

Geographic origins of natural gas

To examine the sensitivity of the GHG emissions estimates to changing geographical origins of UK gas supply, the supply of gas was projected forward to 2050 based on DECC projections as discussed above. The presumed decline of UK North Sea gas generates three sub-models that are explored here, specifically:

- **Fuel mix 1 (S1).** The 2015 geographic distribution of natural gas supply extends through 2050 in the same distribution as 2015. The total gas demand fluctuates according to DECC and Oil & Gas Authority (OGA) [2,15,22] estimates to 2035; the 2035 value extends to 2050. This gives the baseline emissions figures;
- **Fuel Mix 2 (S2).** The total UK gas demand fluctuates identically to fuel mix 1. As UK gas declines in production from 2020 through 2050 (DECC estimates end in 2035), North Sea gas from Norway increases to meet gas demand in place of falling UK production. Imported LNG supplies the same percentage of demand from 2015 forward. This demonstrates the shifting responsibility of extraction and transportation emission away from the UK, while total atmospheric emissions are equal;
- **Fuel Mix 3 (S3).** UK gas demand fluctuates as in fuel mixes 1 and 2, UK gas declines in production from 2020 through 2050, and Qatari LNG increases in supply to meet gas demand in place of falling UK production. This model also demonstrates a shift of responsibility for extraction and transportation away from the UK, and places more emphasis on GHG-intense LNG from Qatar.

Results and discussion

EOR emissions versus CCS emissions

Without the use of EOR, a single CCS project can be deployed to nearly meet the DECC projection of 5 Mt CO₂ injected yr⁻¹ by 2030 [3,19]. Any of the CCS projects modeled here would inject 4.95 Mt CO₂ yr⁻¹ starting in year 1 of injection, and continue for 20 years. The coupled EOR-CCS model projects 100 MM bbls of EOR-produced oil production over the course of the 20-year project. This oil contains an additional 44.83 Mt CO₂e in downstream emissions from oil

refining (4.47 Mt CO₂e) and combustion (40.36 Mt CO₂e). It is assumed that the EOR-produced oil negates 100 MM bbls of oil being imported to the UK, thereby negating extraction and transportation emissions from oil produced elsewhere. In the case of Saudi oil, extraction emissions for 100 MM bbls are 3.93 Mt CO₂e and transporting this oil emits a further 0.62 Mt CO₂e [23]. These values assume port-to-port emissions from Saudi Arabia to the USA; transportation to the UK would likely be lower.

A key assumption of the EOR operation is that the 100 MM bbls of incremental oil will negate the same quantity of imported oil from another source. If imported oil is Saudi light oil, extraction, transportation, refining, and combustion of Saudi oil is 493.8 kg CO₂e bbl⁻¹ [23] compared with 448.3 kg CO₂e bbl⁻¹ for domestic EOR-produced oil described above. For the purposes of this study, the North Sea EOR-produced oil is assumed to have negligible transportation emissions; production emissions are counted in the EOR model.

EOR-to-CCS project

Under the coupled EOR-CCS scenario, after a 20-year EOR project is completed the complete infrastructure for further CCS has been financially subsidized by production of 100 MM bbls of EOR oil. This would represent a very substantial savings for the UK Treasury as no CCS subsidy is needed. It would also represent a savings for the UK electricity customer, as infrastructure costs are paid via EOR revenue rather than rising electricity prices. A full economic analysis is beyond the scope of this study, but would be an important next step for this approach.

After a typical 20 years of CO₂-EOR oil production lifespan, the pipeline and borehole infrastructure has 20–40 years of remaining life, and can be converted to operate as injection of pure CO₂ for storage into storage destinations well proven by CO₂-EOR injection [21]. If each EOR project transitions to CCS for an additional 20 years, annual injected CO₂ increases from 4.62 Mt CO₂ yr⁻¹ to 4.95 Mt CO₂ yr⁻¹ and annual net emissions reduction increases from – 0.94 Mt CO₂ yr⁻¹ (coupled EOR-CCS) to – 1.66 Mt CO₂ yr⁻¹ (CCS only) when oil imports resume.

As such, a 40-year EOR-to-CCS project that switches to CCS only in year 20, and uses only North Sea Gas, stores 192.7 Mt CO₂e, and emits 139.5 Mt CO₂e – a net carbon reduction of over 50 Mt CO₂e per project. These figures include 100 MM bbls of EOR oil in the first 20 years, and 100 MM bbls of Saudi oil imported during the final 20 years. During the EOR phase, the project produces grid electricity while emitting 305 kg CO₂e MWh⁻¹, including the emissions associated with the EOR-produced oil. During the CCS phase, grid

electricity is produced at 273 kg CO₂e MWh⁻¹ including the emissions from imported Saudi oil.

If during the CCS phase no oil is imported to replace the EOR oil supply, grid electricity emissions intensity reduces to 68 kg CO₂e MWh⁻¹ for a single CCS project. Of course, a project does not use gas from one geographic origin; rather it uses what is supplied by the NTS, as discussed above.

Stamford and Azapagic [11,15] assumed a lifespan of 25 years for a gas plant. It is here assumed that, because construction emissions are less than 0.2% of total life-cycle emissions [11], the extension of a service life of a gas plant to 40 years for the EOR-to-CCS model would have a negligible impact on overall project emissions savings.

EOR-to-CCS in the context of UK climate targets

DECC [7] projects that new CCS will contribute 638 MW of new power capacity in 2019, growing to 3527 MW in 2030 and 8382 MW in 2035. However, this capacity will contribute 2.55 TWh of electricity in 2019, growing to 23.14 TWh in 2030 and reaching 39.5 TWh in 2035. A single EOR-to-CCS project delivers 12.1 TWh to the grid from 1930 MW of capacity, and meets the DECC CCS capacity and electricity projections for 2025.

The CCC's Fourth Carbon Budget suggested that the carbon intensity of electricity in the UK would need to fall to 50 g CO₂e kWh⁻¹ by 2030 with a mixture of

renewables, nuclear and CCS [2]. In response to this, Element Energy [12] modeled scenarios to fulfill the carbon intensity target, storing 52 Mt CO₂ in 2030 with coal CCS, gas CCS and industrial sites. This is a highly ambitious scenario in this context. However, it is included to illustrate the very large commitment required by the UK to reach the 50 Mt CO₂ yr⁻¹ stored by 2030. This is of particular importance and relevance because of the statement made by Element Energy that without CCS, reaching climate targets would double costs to all industries from a minimum £30 billion per year in 2050 [24]. Calculations show that reaching this storage goal is possible with only gas power through 11 EOR-to-CCS projects, starting one per year in 2020 (a scenario that is also in line with DECC and BEIS projections of new unabated gas capacity in the UK through 2035 [7,4]).

By deploying one EOR-to-CCS project per year from 2020 onward, the suite of projects examined here also builds capacity at the same pace as DECC's projection [7] for unabated gas power, while capturing CO₂ and lowering the grid intensity of UK electricity supply. As previously stated, deploying just one project meets the current projections for CCS capacity projections (see Figure 3).

If CCS alone were deployed to meet the Element Energy target, 54.5 Mt CO₂ would be injected by year 11 (2030), storing 1416 Mt CO₂ by 2050. However, EOR does reduce the CO₂ injection rate after year 2. Eleven EOR projects would inject 51.8 Mt CO₂ by 2030,

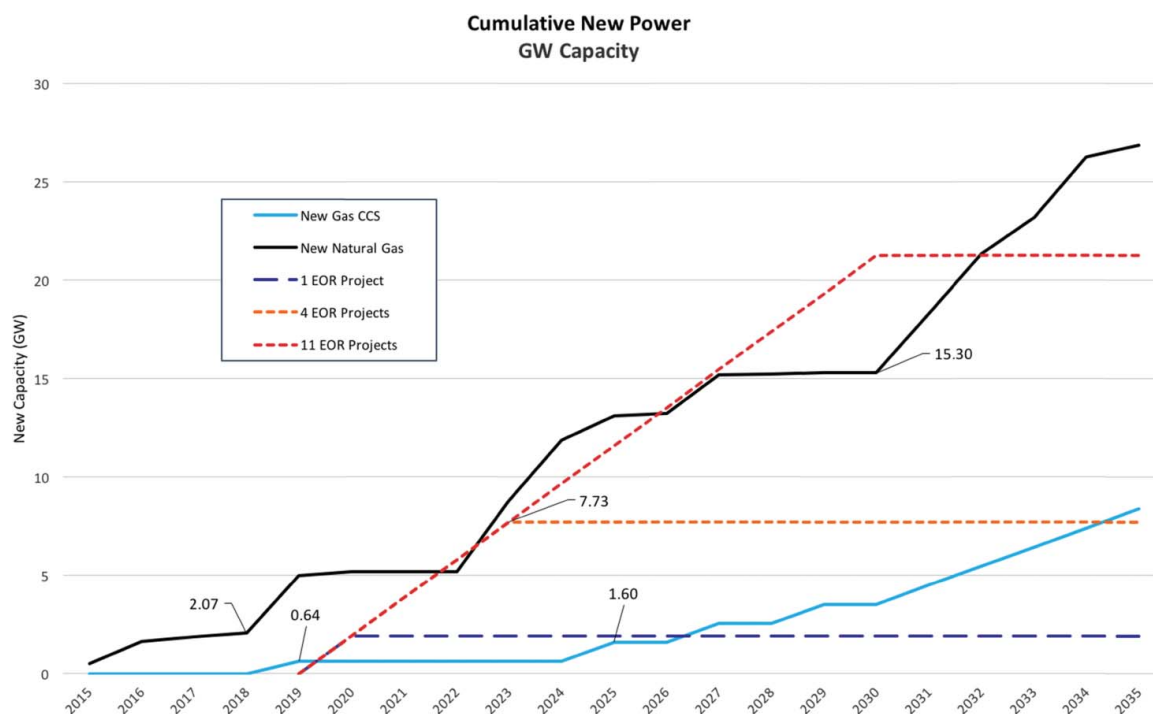


Figure 3. Cumulative required new power capacity from 2015 to 2035 [7]. DECC projects that new CCS capacity will begin in 2019 with 640 MW (blue line) while 5 GW of new unabated gas capacity will be installed at the same time (black line). Unabated gas is projected to contribute over 27 GW of capacity by 2035. The projections of gas capacity with CO₂-EOR and CCS will contribute 1.9 GW (dashed blue), 7.7 GW (dashed orange), and 21.2 GW (dashed red) of capacity.

meeting the Element Energy [12] goal while providing the additional revenue required for expansion of CCS infrastructure. If these 11 EOR projects were mandated to continue to CCS after 20 years of EOR, 1358 Mt CO₂ would be stored by 2050; that is a 56 Mt reduction in CO₂ emissions compared to using only CCS and no EOR, with oil imported from Saudi Arabia. Considering all emissions with EOR and CCS operations, including combustion of resumed Saudi oil imports, this suite of projects emits 1076–1204 Mt CO₂ from 2020 to 2049, while storing 1358 Mt CO₂. If Saudi oil imports do not resume after EOR operations, total emissions are reduced to 940–1068 Mt CO₂ from 2020 to 2049.

Coupled EOR-CCS and UK oil sources

The suite of coupled EOR-CCS projects considered here would provide 132 TWh of grid electricity by 2030 between 152–184 kg CO₂e MWh⁻¹ without considering the EOR-produced oil. As each EOR project reaches its 20th year, and transitions to CCS only, the average grid intensity drops to 90–142 kg CO₂e MWh⁻¹ by 2049, assuming oil is not imported or combusted to replace the EOR oil – thus leading to a net reduction of oil use.

Emissions from CCS offshore operations are 1.2 Mt CO₂ for 20 years and for EOR total around 13.5 Mt CO₂ for 20 years. The 100 MM bbls of EOR oil contains 44.83 Mt CO₂ (assuming normal combustion); 100 MM bbls of Saudi oil (imports during CCS with combustion) contains 49.38 Mt CO₂. The sum of these differences indicates that a CCS project emits 7.75 Mt CO₂ less than an EOR project over 20 years when comparing CO₂ sourced from the same power plant. Therefore, if CCS is performed while importing oil with greater than 571.3 kg CO₂ bbl⁻¹ embedded, EOR is actually more advantageous. This embodied carbon penalty of oil source requires low-carbon production sources, and so would eliminate most shale oil and other synthetic crude from North America, as shown in Mangmeechai [23].

Producing oil through CO₂ EOR helps to avoid oil transportation emissions, and incorporates extraction emissions into the EOR process. If the 100 MM bbls displaces Saudi (light) oil, an additional saving of 4.55 Mt

CO₂e from avoided extraction and shipping of Saudi oil is estimated [23]. However, it should be noted that the production and most of the transport GHG emissions associated with oil from Saudi Arabia would fall outside of current UK GHG reporting boundaries for the United Nations Framework Convention on Climate Change (UNFCCC) [25] as well as International Organization for Standardization (ISO) 14064 carbon accounting frameworks [26–27].

The key advantage of the EOR-to-CCS model envisaged in this study is that the EOR oil helps to pay for CCS infrastructure. However, there is the issue of additionality (rather than substitution) of EOR oil. There is an underlying assumption that introducing new EOR oil would stop the same amount of Saudi Arabian oil from being produced.

Responsibility of upstream emissions

As UK gas production declines over the next decade, the projected gas demand remains constant [3,7]. The 2015 gas mix along with gas decline under two fuel-mix scenarios was modeled, as discussed above. When UK gas production declines, and other North Sea gas replaces the supply (S2), the responsibility – in terms of current reporting requirements – of gas production-related GHG emissions shifts away from the UK, while actual GHG emissions to the atmosphere stay constant. This is due to the equal LCA estimates of all North Sea gas, but the shift in responsibility for reporting of extraction and transportation emissions.

For instance, if declining UK gas production is replaced with imported Qatari LNG, GHG emissions to the atmosphere from this source might increase, yet reported UK GHG emissions would decrease (see Table 1 and Figure 4). Under current accounting practices, only the combustion emissions are counted toward the grid intensity of electricity supply. Figure 5 demonstrates the grid intensity of three pathways to illustrate the differences in GHG emissions accounting compared to LCAs.

When comparing all the models and gas sources for CO₂e emissions per unit of power output, EOR from LNG is not as advantageous because of energy associated with liquefying and transporting gas for

Table 1. Upstream emissions associated with gas power production for nine simulations to 2050. The figures do not include emissions associated with enhanced oil recover or carbon capture and storage (EOR/CCS) operations, oil production, end use of oil or stored CO₂. UK emissions are lowest when imported gas is used in the fuel mix. However, atmospheric emissions are highest in Fuel mix 3, which has greater dependence on Qatari liquefied natural gas (LNG).

Upstream emissions through 2050 (Mt CO ₂ e)		Fuel mix 1 UK Gas	Fuel mix 2 Norwegian Gas	Fuel mix 3 Qatari LNG
1 EOR-to-CCS Project	Emissions to atmosphere	32.03	32.03	44.82
	UK emissions (% of total)	20.54 (64.14%)	18.92 (59.07%)	18.92 (42.20%)
4 EOR-to-CCS Projects	Emissions to atmosphere	121.91	121.91	172.06
	UK emissions (% of total)	78.20 (64.14%)	71.83 (58.92%)	71.83 (41.74%)
11 EOR-to-CCS Projects	Emissions to atmosphere	295.47	295.47	423.52
	UK Emissions (% of total)	189.53 (64.14%)	173.26 (58.64%)	173.26 (40.91%)

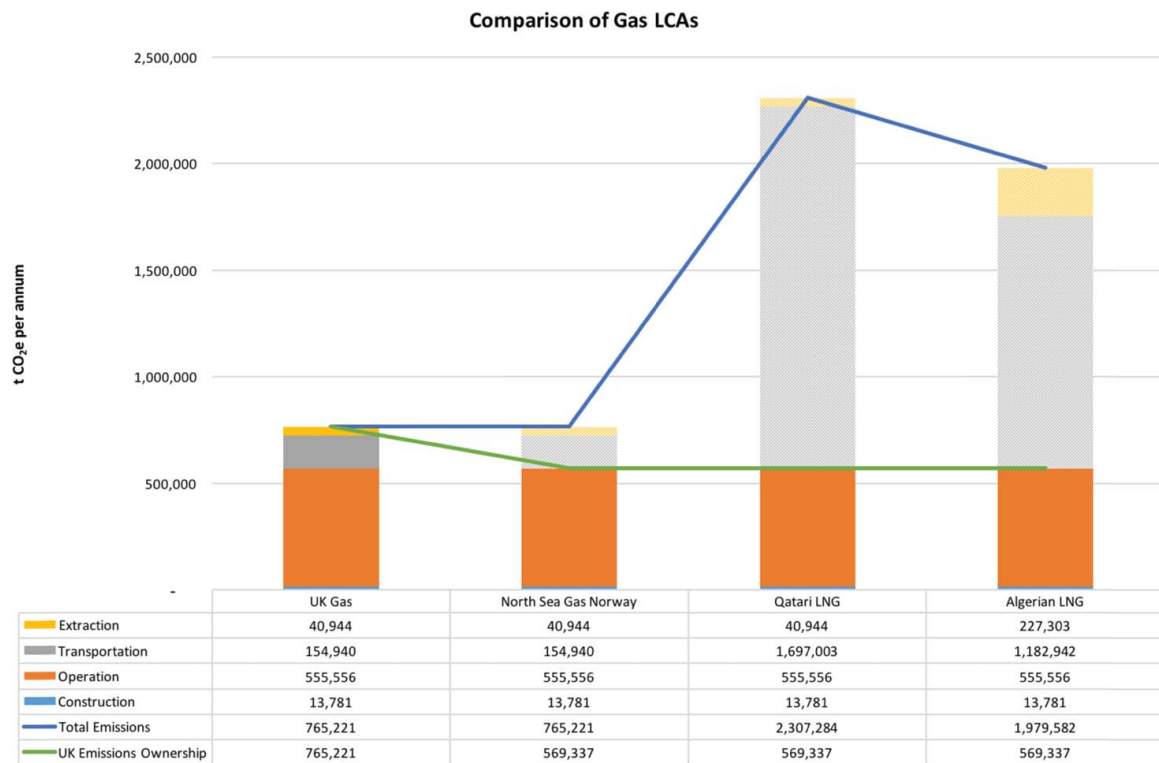


Figure 4. Comparison of onshore gas LCAs from Stamford and Azapagic [11] for UK EOR and CCS. Under current emissions accounting practices, the UK would be responsible for emissions associated with construction and operation of plants in the UK, but not extraction and transportation outside of the UK (partially shaded). Using Qatari LNG would result in the highest GHG emissions to the atmosphere but the UK would have the lowest share of emissions ownership. The current accounting practices incentivize the UK to pursue the cheapest gas, regardless of total GHG emissions.

LNG [11,15]. North Sea gas appears to be the best option for CCS and EOR in this context due to the low production, transportation and operational emissions. However, 'UK-owned' emissions would be lowest using

Qatari LNG because the emissions associated with extraction and transportation are regarded as foreign emissions under current GHG accounting regimes (see Figures 4 and 5).

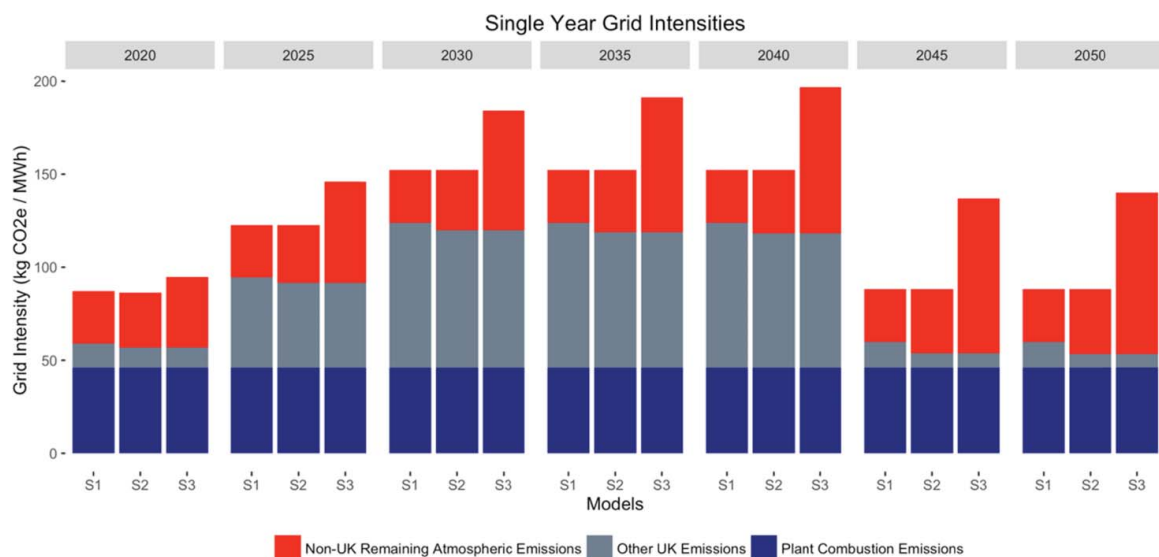


Figure 5. Single-year grid intensity for three EOR-to-CCS fuel-mix simulations. Plant combustion emissions are counted toward grid intensity under current GHG accounting practices. Other UK emissions are also counted toward the UK total emissions, but not counted toward grid intensity. These emissions include plant construction, UK fuel extraction and transportation and EOR operational emissions. Non-UK emissions include fuel extraction and transportation occurring outside the UK. Current accounting practices incentivize the UK to minimize domestic emissions (S2 or S3) for carbon budget targets and lower grid intensity.

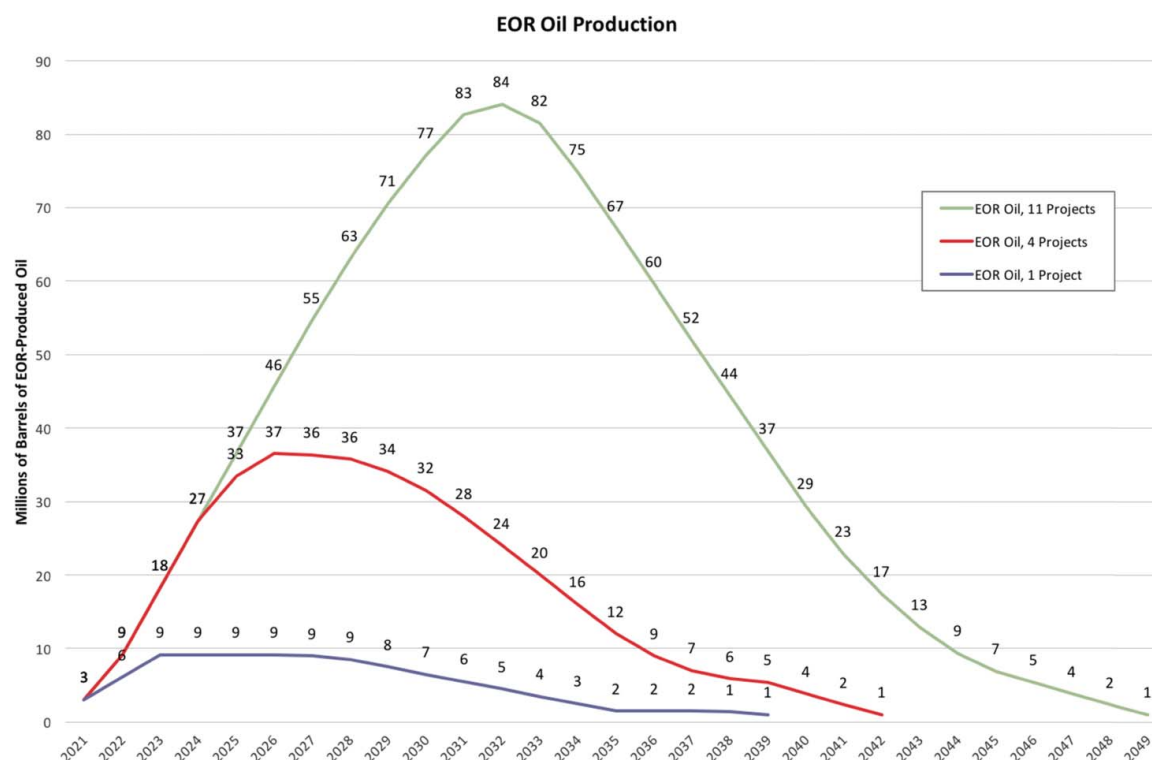


Figure 6. EOR oil production per year from Stewart and Haszeldine [8]. A single EOR project (purple) produces 77.8 million barrels of EOR oil in the first 10 years. The final 5 years produces 6.88 million barrels. A suite of 11 projects produces 405 million barrels in the first 10 years.

Other upstream gas sources

DECC's projected demand for natural gas power would likely have other effects not examined in this paper. Continued demand for natural gas, along with declining North Sea gas production, could incentivize new domestic gas sources, or other sources from abroad.

Stamford and Azapagic [11] also estimate the GHG emissions of UK shale gas used for electrical power to be 412–1102 kg CO₂e MWh⁻¹, with a central estimate of 462 kg CO₂e. Using the same methodology as above, utilizing this gas in CCS would correspond to a grid intensity of 76.8–898.3 kg CO₂e MWh⁻¹ (136 kg CO₂e mean), depending on limits to extraction emissions. This is an area in need of further study, as the UK plans to move forward with a shale gas agenda.

Increased UK gas demand could increase demand on the supply entering the NTS from The Netherlands and Belgium. This could increase gas supplied from Russia to the European Continental grid. This gas is of unknown LCA values, and would see an unknown change in atmospheric emissions.

Finally, the UK could also import gas from the USA. This gas would likely be shale gas transported as LNG, which contains increased extraction emissions, and LNG processing and transportation emissions.

UK shale gas is the only option of the above three that would add to the UK GHG emissions total.

However, the global GHG footprint for each of these additional options is the subject of further study.

Conclusions

The goal of 50 Mt CO₂ stored can be achieved by 2030 with the use of 21.2 GW of gas capacity at baseload utilization (constant 85% load factor) using coupled CCS-CO₂-EOR. However, this is achieved through the production of 1100 MM bbls EOR oil, and immediate development of these modeled projects. Considering all greenhouse gas emissions – from power generation, EOR and CCS operations, and oil production and combustion – this project suite emits an estimated 940–1068 Mt CO₂e from 2020 to 2049, while storing 1358 Mt CO₂.

Additional emission savings could occur if replacement oil imports do not continue after EOR operations cease. The grid factor could be reduced from 273.9–388.1 kg CO₂e MWh⁻¹ during EOR to 294.7–346.8 kg CO₂e MWh⁻¹ during CCS. If oil is excluded from the CCS phase – or is not imported to replace EOR oil – the grid factor reduces again to 90.3–142.4 kg CO₂e MWh⁻¹ (see Table 2). On an annualized basis, these projects emit 3.31–4.69 Mt CO₂e yr⁻¹ compared to the current BAU case, which emits 8.50–9.09 Mt CO₂e yr⁻¹ (see Table 3). In any fuel-mix scenario, the projects modeled above are better than the BAU scenario of combusting unabated natural gas.

Table 2. Annual project emissions as grid factors for one EOR-to-CCS project compared to a BAU scenario. In all fuel-mix scenarios, the EOR-to-CCS project produces fewer emissions than the BAU scenario of the same mix. The BAU scenario compares the same power plant as in the EOR-to-CCS scenario, but delivers more power to the grid because no CO₂ is captured for EOR/CCS. The BAU emissions include the UK portion of fossil fuel production emissions.

Annual emissions per project (kg CO ₂ e MWh ⁻¹)	Fuel mix 1 <i>UK Gas</i>	Fuel mix 2 <i>Norwegian Gas</i>	Fuel mix 3 <i>Qatari LNG</i>
EOR phase	247.5–250.7	247.5–254.5	257.9–291.3
Including EOR oil	273.9–344.4	273.9–344.4	286.3–388.1
CCS phase	90.3–98.6	90.3–98.6	102.7–142.4
Including imported Saudi oil	294.7–303.0	294.7–303.0	307.0–346.8
BAU emissions (no EOR/CCS) Including imported Saudi oil	591.1–595.0	591.1–595.0	601.5–631.7
BAU emissions (no EOR/CCS) excluding oil emissions	419.5–423.3	419.5–423.3	429.9–460.1
BAU emissions (no EOR/CCS) excluding oil emissions, UK fuel production & power emissions only	393.7	388.6–394.8	377.6–408.8

Table 3. Annual project emissions. In all fuel-mix scenarios, the EOR-to-CCS project produces fewer emissions than the BAU scenario of the same mix. The BAU scenario compares the same power plant as in the EOR-to-CCS scenario, but delivers 2.4 MWh more power to the grid because no CO₂ is captured for EOR/CCS.

Annual emissions per project (Mt CO ₂ e)	Fuel mix 1 <i>UK Gas</i>	Fuel mix 2 <i>Norwegian Gas</i>	Fuel mix 3 <i>Qatari LNG</i>
Upstream power plant with CO ₂ capture	1.03–1.09	1.03–1.09	1.18–1.62
EOR/CCS operations	0.03–0.83	0.03–0.83	0.03–0.83
CO ₂ stored	(4.62–4.95)	(4.62–4.95)	(4.62–4.95)
Embedded oil emissions	2.24–2.47	2.24–2.47	2.24–2.47
Total annual project emissions	3.31–4.16	3.31–4.16	3.46–4.69
BAU power emissions	6.03–6.09	6.03–6.09	6.18–6.62
BAU oil emissions	2.47	2.47	2.47
BAU total emissions	8.50–8.56	8.50–8.56	8.65–9.09

These savings could occur if EOR operators are contracted to continue CCS operations for an additional 20 years after the end of EOR operations. It is assumed that the financial incentive of producing 100 MM bbls per project will pay for the operational costs of 20 more years of CCS. In reality, policy action and/or carbon prices will be needed to force continued storage.

The above savings also rely upon decreases in oil use after EOR oil is no longer produced. If, when EOR transitions to CCS and EOR oil no longer is produced, oil imports continue, the advantage of CCS is decreased through the additionality of replacement oil. This assumes that the UK will decrease oil usage by 2040, when the first EOR-to-CCS project transitions to CCS. This also assumes that 1100 MM bbls of EOR oil from 2020 through 2049 does not exceed demand and over-supply the UK and global markets. Current DECC projections indicate that the demand for oil in the UK will not decrease below 500 MM bbls yr⁻¹ before 2035 under any of the seven modeled policy scenarios [7]. Annual EOR oil production from 11 EOR-to-CCS projects will peak in the year 2032 with 84 MM bbls, well below the 500 MM bbls yr⁻¹ projected demand (see Figure 6).

The current scenarios assume deployment of these projects in 2020 in order to reach the goal of 50 Mt CO₂ yr⁻¹ stored by 2030; however, funding cuts have delayed the development of CCS. Recent funding pledges [16,17] indicate a continued commitment to CCS. Considering these delays in combination with

project development timelines, and legally binding carbon reduction commitments, the 2030 goal of 50 Mt CO₂ yr⁻¹ stored is in jeopardy, which could cost UK industry £30 billion per year after 2050 [24].

Finally, it is assumed that the reduction of 1100 MM bbls of imported oil will aid in lowering UK GHG emissions, but it is also assumed that the previously imported oil is no longer produced. The use of EOR oil introduces new oil into the global system. If the previously imported oil is still produced, and EOR oil is used, then there may be a small increase in oil-based GHG emissions globally. The 1100 MM bbls of oil, additional or not, are trivial in comparison to the reduction realized in achieving CCS through the use of EOR. On a full life-cycle analysis, with the unusual aspect of lining across the economy from electricity to oil, this aggressive CCS-EOR scenario provides a net carbon reduction. More carbon is stored, sooner, for less public funding, than by any rival method.

Acknowledgments

Funding was provided to the project by a group of government and oil company sponsors, but those sponsors have no control over the reporting of research results. Jeremy K. Turk is funded by The Energy Technology Partnership, The University of Edinburgh, Scottish Carbon Capture and Storage, and Edinburgh Centre for Carbon Innovation. David S. Reay is funded by NERC. R. Stuart Haszeldine is funded by the Scottish Funding Council, the Scottish Government, EPSRC and NERC.

Disclosure statement

No potential conflict of interest was reported by the authors.

Funding

This work was supported by the Engineering and Physical Sciences Research Council; Natural Environment Research Council; The Scottish Government; Edinburgh Centre for Carbon Innovation; Scottish Carbon Capture and Storage; Energy Technology Partnership (studentship #129); The University of Edinburgh; and Scottish Funding Council.

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